Ontario Energy Board Commission de l'Énergie de l'Ontario

Development of Filing Requirements for Transmission Infrastructure Investment (EB-2005-0470)

Staff Discussion Paper for Technical Advisory Team

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1. Introduction

On August 26, 2005, the Ontario Energy Board (OEB) released a public notice announcing its commitment to develop filing requirements for transmission infrastructure investment. The notice recognised that there is a need to clarify the approach used for evaluating the costs and benefits of transmission infrastructure investment. The filing requirements may also apply in rates cases in which the OEB may review transmission capital expenditures.

The Board has made no decisions at this stage about the type of filing requirements or method of evaluation that it will ultimately adopt. In this paper, OEB staff have developed a potential investment test which will be the starting point for discussions with a Technical Advisory Team that will assist the Board in developing draft filing requirements. After considering the input of the team on the conceptual and practical merits of the potential test, the Board will develop a draft test and draft filing requirements that will be released for public comment. The public comments received will be used in preparing the final filing requirements.

The primary purpose of this paper is to present a potential test for evaluating transmission investments and an overview of the important issues related to evaluating the costs and benefits of transmission infrastructure investment. Having an agreed upon method of evaluation raises the question whether receiving approval from the Board for a leave to construct obviates the need for a separate approval for cost recovery of an investment in a rates case. However, that is not the primary purpose of this process, although it is likely that the Board will review the relationship between rate recovery, leave to construct applications and the Ontario Power Authority's (OPA's) Integrated Power System Plan following the conclusion of this process.

2. The Board's Role in Transmission Infrastructure Investment

The OEB is responsible for regulating natural gas and electricity utilities. With respect to electricity, the Board is to be guided by the following objectives stated in section 1(1) of the *Ontario Energy Board Act, 1998* (the "Act"):

> **1.** (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
>
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

With respect to electricity transmission, leave of the Board is required under section 92 of the Act for the construction, expansion or reinforcement of an electricity transmission line as well as for the making of a connection.

Under the *Definitions and Exemptions Regulation 161/99*, a variety of projects are exempt from need for leave to construct hearings:

> **6.2** (1) Subsection 92 (1) of the Act does not apply to,
>
> (a) a person that constructs, expands or reinforces an electricity distribution line;
>
> (b) a person that makes an interconnection linking a distribution system with an adjacent distribution system;
>
> (c) a person that constructs or reinforces an electricity transmission line that is 2 kilometres or less in length;
>
> (d) a person that expands an electricity transmission line in length by 2 kilometres or less;
>
> (e) a person that constructs, expands or reinforces an electricity transmission line or makes an interconnection linking a transmission system with an adjacent distribution system, if the construction, expansion or reinforcement of the line or the making of the interconnection began before subsection 92 (1) of the Act came into force;
>
> (f) a person that makes an interconnection linking a transmission system with an adjacent transmission system in Ontario; or
>
> (g) a person that makes an interconnection linking a distribution system with an adjacent transmission system.

The Board's mandate for leave to construct applications under section 92 is to ensure that electricity transmission line expansions are in the public interest. Subsection 96(2) specifies that, for this purpose, "the Board shall only consider the interests of consumers with respect to prices and the reliability and quality of electricity service."

3. The Need for Developing Filing Requirements

There is a need to streamline and standardize the review of electricity transmission capital expenditures for system expansion, reinforcement, reliability enhancement, congestion reduction and line loss reduction.

There has not been a standardized and comprehensive approach to evaluating transmission investment. The institutional restructuring of the electricity sector set out in the *Electricity Restructuring Act, 2004*,also creates a need for clarity about which agencies and organizations are responsible for providing what types of evidence to the Board in leave to construct cases.

In some past leave to construct applications, applicants and intervenors have provided evidence of benefits relating to reliability and system efficiency

enhancement, comparing these benefits to project costs. But in other cases only limited evidence on measured benefits (e.g., reduced congestion and line losses) has been developed.

Furthermore, Ontario is about to embark on a period of large investments in electricity infrastructure, including transmission. Hydro One and the Independent Electricity System Operator (IESO) have identified many reliability-based transmission investments. The OPA's future Integrated Power System Plan is likely to identify other necessary transmission investments.

It is anticipated that the Board will receive a number of leave to construct applications over the next few years and will also review transmission investments not covered by section 92 in the context of transmission rates cases. As a result, there is a need to establish clear and definitive filing requirements for transmission projects. This will allow for greater predictability in the review of these applications, including who has the responsibility to file appropriate evidence.

Section 4 explains the objectives and principles of a potential test that could be used and identifies issues for discussion.

4. Cost-Benefit Elements and Framework

This section describes the elements and framework of the potential investment test developed by OEB staff and presented in Appendix A. The method of evaluation in the potential investment test is a cost-benefit analysis that would be used to evaluate and rank transmission investment proposals compared to alternatives. This section explains the elements and framework of the potential test:

a) Benefits of Transmission Investment
b) Maximizing benefits
c) Modelling parameters
    i) Materiality Threshold
    ii) Value of unserved energy
    iii) Discount Rate
    iv) Timeframe
    v) Alternative Projects
    vi) Uncertainty

Each section concludes with "Issues for discussion," indicating areas where the input of Technical Advisory Team is expected to be particularly valuable in ensuring the development of an effective and efficient evaluation.

The potential test presented in this paper was developed by examining the cost-benefit methodologies for transmission investment developed in California, Australia and New Zealand. The methodologies developed share many core elements. At the same time, it should be recognized that these jurisdictions differ from Ontario, and each other, in terms of regulatory framework, state of market development, geography and other factors. And no single model of evaluation is likely to be applicable to all jurisdictions.

When developing its cost-benefit test for transmission investment, the Australian Competition & Consumer Commission (ACCC) summarized the general principles of cost-benefit analysis, including:[1]

- The measurement of economic value of benefits and cost is based on either the value of a consumers' 'willingness to pay', 'opportunity cost', or 'economic cost'. This provides the basis for determining the return available from the most attractive alternative use of the resources for a given project;
- The benefits and costs of a project occur over time and for comparative purposes should be considered at a common date. This is achieved by using a suitable discount rate and discounting future cash flows back to the present. The NPV of the project is the present value (PV) of its benefits minus the PV of its costs, and for socially desirable projects should be greater than zero
  [...]

[1] ACCC, *Review of the Regulatory Test for Network Augmentations, Final Decision*, August 2004, p. 19.

- Risk and uncertainty need to be accounted for. Various techniques to account for risk and uncertainty include the use of [expected values calculated by assigning probabilities to the likelihood of an event occurring], sensitivity analysis, setting a cut-off period in which the cost and benefits are assessed, and using a higher discount rate for benefits after a stipulated period.

Ideally, analysis would take into account all costs and benefits associated with a project with the difference between an investment's discounted benefits and its discounted costs indicating the value of the investment to society.

However, some benefits (e.g., access to cleaner power) and costs (e.g., environmental costs) are not readily quantifiable. Reliability benefits are also difficult to quantify (further discussed below). The Board's investment test should state whether non-quantifiable benefits will be considered and, if they are considered, under what circumstances and how.

For example, New Zealand's Grid Investment Test[2] states that "Where a material market benefit or cost cannot be quantified, the direction of the market benefit or cost and likely magnitude of the market benefit or cost must be identified." In contrast, Australia's Regulatory Test states that "any cost or benefit which cannot be measured as a cost or benefit to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded."

a) Benefits of Transmission Investment

Transmission investments reviewed by the Board typically fall into two main categories: connecting generation/load (i.e., radial lines) and "deeper" grid (or network) investments.[3] "Deeper" grid investments can be subdivided into investments initiated to maintain or augment system reliability and those initiated to increase system efficiency. In some cases, radial line investments may necessitate "deeper" (network) investments.

The most significant issue to emerge from the Niagara reinforcement decision[4] was the submission of what the Board considered incomplete quantified benefits during the proceeding. The decision noted that:

> The Board found that there were reliability and enhanced supply benefits from transmission reinforcement on the Queenston Flow West interface, but was

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[2] For an application of the test see Transpower, *North Island 400 kV Upgrade Project, Investment Proposal*, 2005 (see Part IV – Cost Benefit Analysis).

[3] Paul L. Joskow, *Patterns of Transmission Investment*, March 2005.

[4] OEB, *Application by Hydro One Networks Inc., for an order or orders granting leave to construct a transmission reinforcement project in the Niagara Peninsula area*, Decision and Order, EB-2004-0476, July 2005; see also OEB, *Application by Hydro One Networks Inc., for an order or orders granting leave to construct a transmission reinforcement project in the Niagara Peninsula area*, Interim Decision, EB-2004-0476, May 2005.

> unable to adequately consider the economic impact of the project. Although the Act does not require the Board to make specific findings on economic impact, and also does not require the Board to conclude that there is a net positive economic impact it is difficult for the Board to make a finding that a project is in the public interest without understanding the economic costs and benefits of the project.

Overall, the process revealed the need to clarify the evidence that the Board requires to make an informed decision on investment proposals to ensure the public interest is protected. At the time, there were no guidelines specifying that a comprehensive cost-benefit analysis, comparing project costs and benefits, was required for leave to construct applications.

A robust investment test needs to take into account and identify the wide range of costs and public interest benefits for the electricity sector that can arise from transmission investments, such as[5]:

- Improved market efficiency through relieving congestion (i.e., bottlenecks caused by physical limits on transmission facilities)
- Improved market efficiency through increased competition (e.g., new generator entry) resulting in reduced market power, lower prices, and increased output
- Reduction in line losses
- Emergency support and sharing of reserves/ancillaries
- Operational flexibility
- Deferral of additional investments in transmission and/or generation
- Increased reliability of delivery to consumers
  - Improved security of supply
  - Improved adequacy of supply
- Ability to meet new demand
- Improved diversity of supply
- Access to cleaner power

Projects also involve costs, such as:

- Costs incurred in constructing or providing the proposed investment;
- Operating and maintenance costs over the operating life of the proposed investment;

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[5] See Transmission Planning Working Group, *Draft Interim Report and Recommendations of the Transmission Planning Working Group on Facilitating the Transmission Planning and Approval Process in the Competitive Marketplace*, February 2004; CAISO, *Transmission Economic Assessment Methodology*, June 2004.

- The cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, and land management; and,
- Costs incurred in decommissioning the proposed investment.

The benefits listed above are typically classified as being either "economic" or "reliability" benefits. Economic benefits refer to benefits that improve market efficiency (e.g., congestion relief, reduced line losses, increased competition among generators). Reliability benefits refer to increased adequacy and security. Adequacy benefits increase the ability of the system to supply consumers with their energy requirements over time; for example, reducing the need for public appeals to lower consumption (i.e., voluntary load curtailment). Security benefits increase the ability of the system to withstand contingency events, for example, the ability to withstand an unexpected transformer or generator failure. There may be other public benefits resulting from transmission investment (e.g., access to cleaner power).

Some economic benefits such as reduced congestion costs and lines losses have been quantified in past leave to construct applications reviewed by the Board.

Quantifying reliability benefits warrants further discussion.[6] Past leave to construct cases have involved reliability benefits, but no case presented quantified reliability benefits. The Board requested reliability benefits to be quantified in the Niagara reinforcement hearing, but the evidence requested was not produced.

Deterministic Reliability Standards

Most jurisdictions have minimum reliability standards, requiring the transmission network to meet pre-determined technical and engineering criteria. For example, deterministic standards may prescribe that the transmission network be able to handle specific voltage requirements, or withstand certain contingency events (e.g., transformer or generator failure). Standards are typically based on a set of subjectively determined worst-case scenarios. With deterministic reliability standards, if a standard is violated an investment in transmission infrastructure is required to restore the standard. These characteristics make deterministic standards easy to understand and act on. However, a planning framework that relies exclusively on deterministic standards may give undue weight to large but low-probability events and thus may result in an uneconomic, "over-building" of the transmission network.[7]

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[6] For more discussion of reliability standards see Parsons Brinckerhoff Associates, "Probabilistic Transmission Planning, Comparative Proposed investments & Demonstration," Prepared for the New Zealand Electricity Commission, August 2004; Frontier Economics, *Draft Grid Investment Test, Final Draft Discussion Paper*, prepared for the New Zealand Electricity Commission, June 2004.

[7] See Parsons Brinckerhoff Associates.

In Ontario, minimum reliability standards are found in the practices of transmission owners, the OEB's Transmission System Code (TSC), legislation, regulations and standards (e.g., reliability standards established by the IESO, Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Council (NERC)).

If the benefit of satisfying deterministic standards has not been explicitly valued, they cannot be incorporated into a full cost-benefit analysis to determine if a given project has a positive net benefit. Further, projects that are initiated solely to meet deterministic reliability standards without any "economic" benefit may not necessarily have a positive net benefit. That is, in certain circumstances, the best project to satisfy reliability standards would be the one costing the least compared to alternative projects (i.e., neither the project nor any of the alternatives generates a net positive benefit). The test should take this possibility into account.

New Zealand's investment test recognizes that investments prompted by failure to meet reliability standards may not necessarily have a positive net benefit. As a result, New Zealand's investment test states that approval of an investment required to meet a reliability standard prescribed by regulation will be granted when "the proposed investment maximizes the expected net market benefit or minimises the expected net market cost compared with a number of alternative projects."

Probabilistic Reliability Standards

An alternative (or complement) to a deterministic standard is a probabilistic standard. Under a pure probabilistic standard, only investments that have a positive net benefit would be approved. Probabilistic standards assess the probability and costs of contingency events.

A probabilistic approach requires data covering several items, including:

- the amount of unserved energy (i.e., lost load) arising from a specified contingency event;
- the value of unserved energy[8] to the consumer(s) experiencing loss of service; and,
- the probability/frequency of contingency events.

While the greater informational requirements[9] of the probabilistic approach come at some cost, its dollar-denominated reliability benefits provide an offsetting

[8] Other terms used to refer to this concept include Customer Interruption Costs (CIC), Value of Lost Load (VoLL), Value of Service (VOS), and Customer Damage Function (CDF).

[9] For example, valuing unserved energy, assigning probabilities/frequencies to a wider range of contingency events and calculating the expected costs of contingencies.

benefit. This approach allows benefits and costs of reliability investments to be directly compared.

A probabilistic approach, by explicitly valuing unserved energy, allows "reliability" investments to be evaluated in a full cost-benefit framework just as "economic" investments are evaluated. Therefore, an expected result of effective probabilistic standards is greater efficiency through a lower likelihood of network "over-building" compared to a system exclusively using deterministic standards.[10]

In practice, many electricity systems, including Ontario, have used a combination of deterministic and probabilistic standards. The test should be able to accommodate both forms of reliability standards, as the choice of which standard to apply will depend on the purpose of the project (i.e., to meet a minimum standard or enhance reliability beyond the minimum).

Quantified reliability benefits were requested by the Board during the Niagara reinforcement hearings. During the hearing it was argued that significant reliability benefits would arise from the project; however, it was not argued by Hydro One, or the IESO, that the project was necessary to meet minimum reliability standards. No quantified reliability benefits were presented to the Board and questions were raised about what party should be responsible for quantifying project benefits.

Filing requirements prescribing the submission of quantified reliability benefits (e.g., New Zealand's Grid Investment Test) and specifying the party (or parties) responsible for submitting such evidence would have expedited the Niagara reinforcement hearing process.

b) Maximizing benefits

The Board is proposing an investment test that uses a cost/benefit framework to better ensure that applicants propose the most efficient transmission upgrade and not just any upgrade that generates a net public benefit or a positive Net Present Value (NPV). That is, the framework should include the principle of maximizing prospective total benefits over total costs. A proposed network upgrade investment satisfies the cost/benefit test if it maximizes the net present value of the market benefit compared to a number of alternative projects, timings and market development scenarios.

To illustrate, at a specific location on the transmission grid there could be two transmission projects that deliver similar types of benefits over similar timeframes. However, the magnitude of the benefits could be very different. For example, one of the projects may generate $1 million in net benefits while the other delivers $100 million in net benefits. The objective of the test would be to ensure that the transmission project providing $100 million in net benefits (i.e.,

[10] See Parsons Brinckerhoff Associates.

the project that maximizes total benefits compared to alternatives) is brought to the Board for approval.

The cost / benefit principles offered here suggest that approved transmission projects should maximize the "total surplus" of the electricity sector. Total surplus is the sum of consumers' surplus and producers' surplus. Consumer surplus is the difference between what consumers are willing to pay for a commodity and the amount they actually paid. Producer surplus is the difference between the minimum price that producers would accept to supply a given level of output and the actual price producers receive. Under these principles a project which merely transfers surplus between producers and consumers but does not increase total surplus would not be viewed as providing a benefit.

Further, to maximize net public benefits the test should not result in a complex and lengthy process that delays efficient transmission investments. Also, the test developed should result in enhanced certainty and predictability of the regulations pertaining to transmission investment.

c) Modelling parameters

The cost/benefit test must clearly define a number of parameters to ensure that the test both maximizes net public benefits and does not result in a complex and lengthy process that delays the development of regulated transmission investment. The key parameters are:

- the materiality threshold;
- the discount rate;
- the timeframe;
- the value of unserved energy;
- the alternatives to the proposed project; and,
- the treatment of uncertainty.

i) Materiality Threshold

As stated earlier, transmission investments reviewed by the Board typically fall into two main categories: connecting generation/load (i.e., radial lines) and "deeper" grid (or network) investments.

Transmission investments made to connect generation/load should be relatively straightforward to evaluate in terms of costs and benefits. In most cases, they will have no, or a relatively minor, impact on ratepayers through impacts on the efficiency and reliability of the network that is shared by all users. Further, connection investments are already subject to the evaluation process set out in the TSC. Therefore, the test should avoid duplicating and conflicting with the TSC.

In contrast, proposed "deeper" investments that have the potential to increase system efficiency and increase system reliability beyond prescribed minimum standards will require more complex and comprehensive analysis because they directly impact the common network and, therefore, all Ontario ratepayers.

The test should be designed with these differences in mind, so that it does not unnecessarily delay investments that are not expected to have significant impacts on system efficiency and/or reliability and only affect a single customer or small subset of customers. Figure 1 illustrates a potential decision rule.

The information contained in the IESO's System Impact Assessments (SIAs), which assesses the impact on system reliability of transmission investment proposals and the relevant licensed transmitters' Customer Impact Assessments (CIAs), used to assess the impact of a project on customers, in addition to other evidence filed by the applicant on the impact of the project, will to a large degree inform the Board on whether the project should be subject to cost-benefit analysis.

Alternatively (or additionally), there could be a threshold, or degree of rigour, based on the cost of proposed investment. For example, New Zealand's test states that "The rigour and comprehensiveness of the analysis undertaken in applying this grid investment test must be commensurate with the estimated capital expenditure required for the proposed investment," but sets no dollar limit.

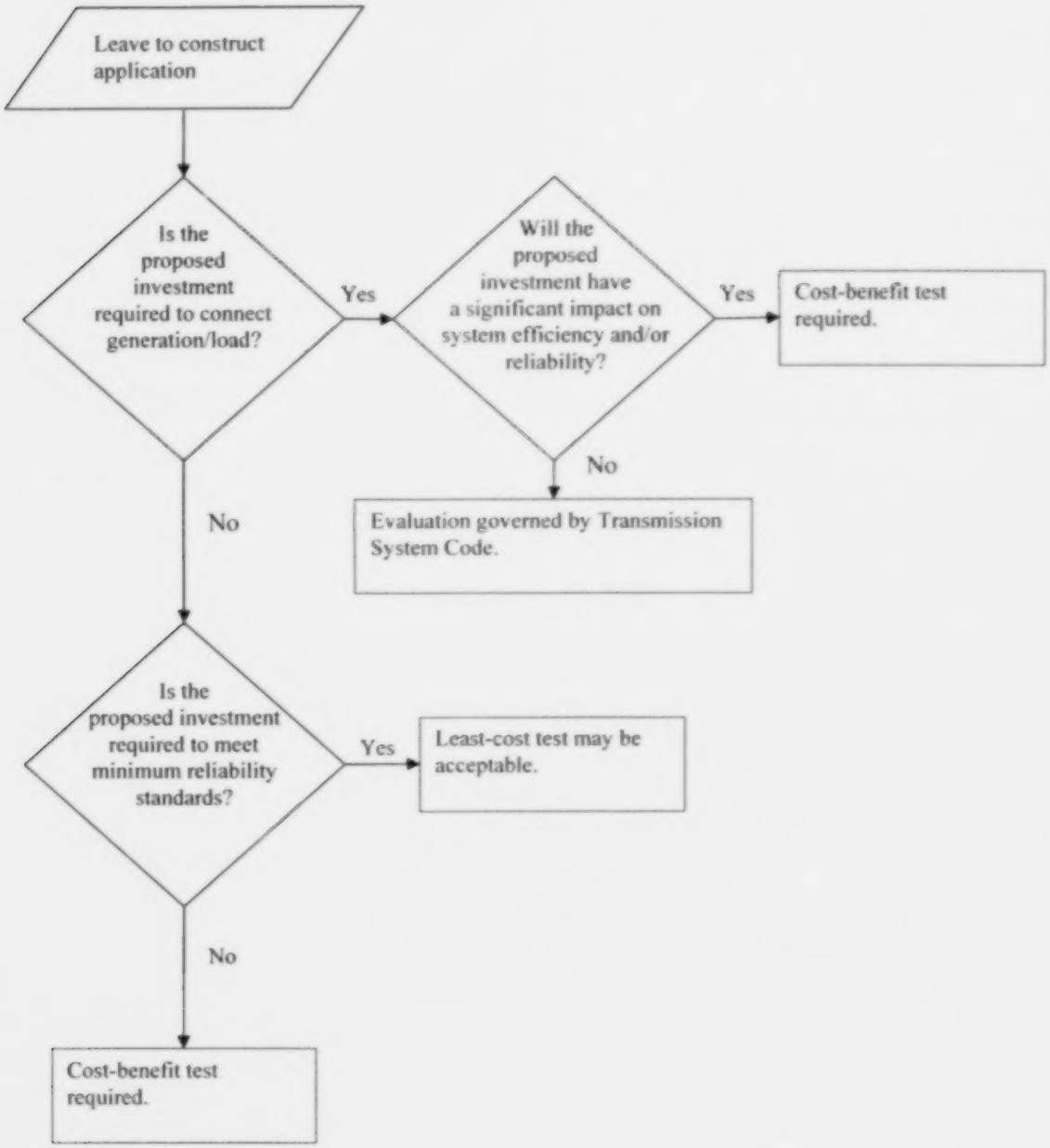
Issues for discussion:

- Should any connection investments be exempt from the test? If so, why?
- Should there be materiality thresholds for applying the test? What should the threshold be based on?

    (a) Type of investment (e.g., exempt connecting generation/load)?
    (b) Dollar value (e.g., degree of rigour based on cost)?
    (c) Combination of (a) and (b)?

- If a simplified test is applied in certain circumstances, what should the test be (e.g., based-on least-cost, workability, risk)?

Figure 1. Proposed Decision Rule for Transmission Investment Test


Leave to construct application
Is the proposed investment required to connect generation/load?
Yes
Will the proposed investment have a significant impact on system efficiency and/or reliability?
Yes
Cost-benefit test required.
No
Evaluation governed by Transmission System Code.
No
Is the proposed investment required to meet minimum reliability standards?
Yes
Least-cost test may be acceptable.
No
Cost-benefit test required.

ii) Value of unserved energy

To quantify reliability benefits, the value that consumers place on unserved energy must be known. That value can be used to determine the benefits arising from reducing the probability of losing service due to system failures or outages.

The value of unserved energy varies between and within consumer classes (i.e., residential, commercial, industrial, agricultural). The value of unserved energy also varies according to when it occurs (i.e., time of day, week and year) and duration of a supply interruption. These factors make the value of unserved energy and, by extension, reliability benefits, difficult to quantify. Ontario Hydro used to measure the value consumers placed on unserved energy through Customer Interruption Costs (CICs) based on customer surveys. Recently, in Australia, a survey to value unserved energy was conducted.[11]

The investment test could specify a value(s) of unserved energy to use for analysis. For example, in New Zealand's Grid Investment Test (GIT), the value of unserved energy is either the value(s) published by the Board or, if no value has been published, NZ$20,000/MWh (about CDN$16,340).

Issues for discussion:

- How should the value of lost load be determined (e.g., consumer surveys, adapting international surveys, or project specific estimates)?
- What organization(s) should be responsible for determining the value of unserved energy (e.g., transmitters, IESO, OPA)?
- Should a single, composite value be used or should a different value be used for different consumer classes?

iii) Discount Rate

A discount rate is required to convert future cash flows to net present values (NPVs). The choice of discount rate can affect the results of a cost/benefit analysis by determining whether a proposed investment has positive or negative NPV and by determining the ranking of projects, depending on the differences in cash flows across projects.

Different discount rates can be used (e.g., pre-tax weighted average cost of capital vs. after-tax weighted average cost of capital) in these types of evaluations. For example, as the purpose of the test is to maximize the public benefits, a public sector discount rate could be used. However, many of the

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[11] For example, see Charles River Associates, *Assessment of the Value of Customer Reliability (VCR)*, prepared for VENCorp, December 2002.

benefits measured are occurring within a market environment, indicating that a commercial discount rate could also be used. The recent Great Lakes Power (GLP) transmission reinforcement case involved debate between GLP and an intervenor with respect to the appropriate discount factor (i.e., pre-tax vs. post-tax cost of capital). Ultimately, the Board decided to accept GLP's after-tax weighted average cost of capital of 7.1%. The test developed should aim to minimize such conflicts by specifying the discount factor to be used. This should also ensure consistency across the various proposed projects and streamline this process.

For example, Appendix 5 of the TSC states that "The discount rate to be used in the [discounted cash flow] calculation shall be based on the transmitter's current deemed debt-to-equity ratio, debt and preference share costs and Board-approved rate of return on equity."

Alternatively, in New Zealand's test, the discount rate used in present value calculations must be the discount rate determined by the regulator, or if a discount rate has not been determined, a discount rate of, or equivalent to, a pre-tax real rate of 7%.

Australia's test states that "The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector."

Issues for discussion:

- What type of discount rate should be used?
- Should a standard prescribed value for the discount rate apply to all projects or are there circumstances where it may be necessary to use a different discount rate? If so, explain why.

iv) Timeframe

The cost-benefit test involves examining costs and benefits over time. The expected future cash flows become more unpredictable and uncertain to estimate as the time frame for analysis becomes longer. As a result, the timeframe used can affect the results of a cost/benefit analysis by determining whether a proposed investment has positive or negative NPV and by determining the ranking of projects, depending on the differences in the realization of costs and benefits over time.

For example, New Zealand's Grid Investment Test prescribes that benefits and costs be examined "over a period of 20 years from the commissioning date (unless significant market benefits or costs are expected to arise from the proposed investment or alternative project after that time, in which case the then-

present value of any future costs may also be included in the cost of the proposed investment or alternative project)."

Issues for discussion:

- What should the timeframe for evaluation be (e.g., 20-years, the lifetime of the investment, horizon over which the investment would be fully depreciated, selected years)?

v) Alternative Projects

Maximizing the public benefit requires that a proposed investment maximizes the net present value of the market benefit compared to alternatives to the proposed project. If the project is not compared to alternatives, it is not possible to make an informed decision with respect to the project maximizing the net public benefit, although it would be possible to decide whether a proposed project had a positive (negative) net public benefit.

The need for a proposed investment to be compared to an alternative implies that a potential alternative need not have a proponent to be included in the test's analysis. However, only proposed investments that are technically and, for projects not required exclusively to meet reliability standards, commercially feasible should be considered alternatives to a proposed investment.

Alternative projects should be projects that would not be developed if the proposed investment or another alternative proceed and likely to proceed if the proposed investment does not proceed (i.e., the projects should deliver similar types of benefits, but not necessarily the same magnitude, as the proposed project). For example, two projects could satisfy the same reliability standards for different durations (e.g., 10 years of meeting reliability standards vs. 15 years).

Alternative projects do not have to be transmission projects. Distributed generation, distribution network enhancement and demand-side management could be alternatives to transmission investments in some cases (e.g., meeting load growth).

It should also be recognized that a possible alternative could be to "do-nothing." Such an option could be a viable alternative for projects proposed for improving efficiency and/or achieving other economic benefits associated with operating, maintaining and managing the transmission system (e.g., the Niagara Reinforcement Project). In this case the "do-nothing" alternative should be considered in the evaluation of alternatives. However, the "do-nothing" option would not be a viable alternative for projects that must proceed in some form, for example, responses to connect load customers or generators that require network reinforcements, or proposed to meet load growth (e.g. York Region).

To ensure that the test is tractable some limit should be put on the number of alternatives considered. For example, New Zealand's tests states that "The alternative projects used in applying this grid investment test must be limited to those appropriate in number and technology given the cost magnitude of the proposed investment, the complexity of the required modelling and the urgency of the proposed investment." Further, when the New Zealand test was being developed, it was noted that it would be advantageous to limit the number of alternatives considered because "If this is not done, some stakeholders that oppose transmission investment may find it worthwhile to suggest a large number of 'alternative' projects in order to delay and confuse a project assessment."[12]

Issues for discussion:

- How many alternatives should be considered (e.g., should there be a minimum (e.g., three) and a maximum (e.g., ten))?
- Should an organization or agency other than the applicant be responsible for developing or seeking consultation on non-transmission alternatives?
- How should the Board proceed if no proponent is willing to make a commitment to an alternative?

vi) Uncertainty

Investment decisions involve risks and uncertainties about the future. Changes in future system conditions can affect the benefits of a network investment and the ranking of proposed investments. Potential risks and uncertainties imply that assessing a transmission investment based only on assumptions of average future system conditions could significantly underestimate or overestimate the net benefit of the project. As a result, the value of a transmission investment should be evaluated over a range of possible future system conditions (or scenarios) to ensure that the investment maximizes the public benefit. In electricity markets, there are many risks and uncertainties, including future load growth, fuel costs, weather, additions and retirements of generation capacities and the location of those generators.

Different scenarios arise through changing input variables (e.g., rate of load growth, expected weather). Scenarios can range from those likely to occur to extreme scenarios with a remote possibility of occurring. The California Independent System Operator's (CAISO) *Transmission Expansion Assessment Methodology* states that the goals of scenario analysis are to answer the following questions:

- What is the expected benefit of a transmission upgrade
- What is the expected or most likely range of benefits

[12] Frontier Economics, p. 18.

- What is the insurance value of a transmission upgrade against extreme conditions and contingencies

And that:

> A comprehensive scenario selection approach should include three kinds of scenarios:
>
> - Scenarios that represent most likely conditions
> - Scenarios that represent extreme "bookend" conditions
> - Scenarios that represent in-between conditions

Scenarios need to take into account future investments in supply, which are not alternatives to the proposed investment (see above). The supply-side scenarios could be comprised of three types of future projects:[13]

- "Committed" projects: actual proposed transmission and non-transmission projects, other than the proposed investment and alternative projects, which are reasonably likely to proceed in the near future regardless of whether or not the proposed investment or any alternative project proceeds (e.g., the project has received all required regulatory approvals and started construction or has set a construction date)

- "Anticipated" projects: an actual proposed project that has not been developed to the degree of a committed project, but considered likely to proceed (e.g., the project is in the process of obtaining regulatory approvals)

- "Modelled" projects: conceptual projects that will likely enter the market in the future, but have not been developed concretely in the way that committed and anticipated projects are. For example, most of Ontario's existing generation capacity will need to be replaced over the next 15 years; however, there is uncertainty regarding how this capacity will be replaced (e.g., transmission, generation or demand-side solutions). This uncertainty can be captured through "Modelled" projects.

The cost-benefit test could require that the investment maximize the net benefit (or minimize the cost) in the greatest proportion of scenarios modelled. Another option could be to require the proposed investment to have the highest probability-weighted average of the net market benefit of the market development scenarios developed. But a probability-weighted method is more complicated as probabilities must be assigned to each market development scenario and there is no obvious methodology for establishing probabilities for different scenarios,[14]

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[13] Frontier Economics, *Draft Grid Investment Test, Final Draft Discussion Paper*, prepared for the New Zealand Electricity Commission, June 2004.

[14] New Zealand Electricity Commission, *Consultation Paper, Draft Grid Investment Test*, September 2004.

although a reasonable approach would appear to be attaching probabilities to market scenarios based on current market conditions.

Table 1 illustrates how the project that maximizes benefits can change depending on the method used. In the table, Project B would be the "best" project if the cost-benefit test required that the investment maximizes the net benefit (or minimizes the cost) in the greatest number of scenarios modeled (i.e., scenarios 2, 3 and 4). Project C would be the "best" project if a probability-weighted average was used. Project A and C would tie for the "best" if a simple average was used (i.e., each scenario is assigned the same probability).

Table 1

		Net Market Benefits of Three Hypothetical Projects		
Scenario	Probability	Project A ($m)	Project B ($m)	Project C ($m)
1	15%	**12**	2	9
2	15%	20	**22**	21
3	40%	36	**41**	40
4	15%	20	**22**	21
5	15%	**12**	2	9
Total	100%	100	89	100
Simple Average		20	17.8	20
Probability-weighted average		24	23.6	25

Source: New Zealand Electricity Commission, *Consultation Paper, Draft Grid Investment Test*, September 2004.

Examining investment proposals over a range of conditions as described above will help mitigate requests for additional information and conflicts between investment applicant(s) and intervenors over expected benefits (e.g., reduced congestion) and input variables (e.g., discount rate) during the hearing process.

Requiring that a range of future market conditions under a range of input variables be modeled to establish the net benefits of the project would have expedited the Niagara reinforcement (and other leave to construct) hearings by reducing conflicts over modeling assumptions and the expected net benefit of the project at issue.

For example, in the case of the Niagara project, the applicant modelled the benefits of the project assuming that the Ontario market adopted locational marginal pricing (LMP). This assumption was challenged on the grounds that Ontario uses a uniform pricing system. While scenarios using a uniform pricing system were not conducted, it was agreed that modeling future market conditions with such a system would result in constraint payment savings would be reduced from $60 million per year (over four years) to $6 million per year over the same period.

Issues for discussion

- What input variables should be used?
- What should the base-case market development scenario be?

- What should the criteria be for determining which projects are included in market development scenarios?
- How many scenarios should be modelled?
- Should the test distinguish between "anticipated" and "modeled" projects?
- What decision rule should be adopted for selecting the "best" project (e.g., majority of scenarios approach or probability-weighted approach)?
- How should the OPA's Integrated Power System Plan be taken into account in market development scenarios?

5. An Alternative Approach

The Alberta transmission investment oversight regime has been extensively revised since the market opened to competition in 1996. The result is a well-organized process with clearly defined roles and responsibilities for all key players. In surveying the Alberta approach, it is important to bear in mind the following significant policy decisions:

- the transmission system is to be planned to "...allow for transmission of 100 percent of in-merit electric energy...when all transmission facilities are in service..." (i.e., no congestion)
- planning will aim at fostering an efficient and competitive generation market.

While these two policy goals of no congestion and enhancing competition may not characterize the current Ontario policy thrust, the Alberta approach provides useful ideas on the incorporation of reliability and congestion reduction benefits into transmission oversight and organizational responsibilities.

Alberta's *Electric Utilities Act* makes the Alberta Electric System Operator (AESO) responsible, not the owners of the transmission network, for transmission planning and justifying project need. Projects are approved by the Alberta Energy and Utilities Board (EUB):

> 33 The [AESO] must forecast the needs of market participants and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements."
>
> 34(1)When the [AESO] determines that an expansion or enhancement of the capability of the transmission system is required to meet the needs of market participants, the [AESO] must prepare and submit to the [EUB]for approval a needs identification document that
>
> (a) describes the constraint or condition affecting the operation or performance of the transmission system and indicates the means by which or the manner in which the constraint or condition could be alleviated,
>
> (b) describes a need for improved efficiency of the transmission system,

including means to reduce losses on the interconnected electric system, or
(c) describes a need to respond to requests for system access service.

The basic approval process for transmission projects intended to supply a large group of customers or meet overall system reliability needs is as follows:[15]

1. Need Identification Document (NID) Application
   - The AESO prepares NID Application for submission to the Board.
   - Application includes alternatives with cost estimates (project costs).
   - Cost estimates prepared by AESO or requested from Transmission Facilities Owner (TFO).

2. EUB Process
   - The Board reviews the NID Application.
   - The Board processes provide opportunity for stakeholder involvement.
   - The Board may approve, conditionally (or partially) approve or deny.

3. AESO Direction to TFO
   - Following Board approval, the AESO prepares a Functional Specification for the project with further detail of project requirements.
   - The AESO requests a Proposal to Provide Service (PPS) from the TFO.
   - The TFO prepares a PPS, which includes a schedule and a cost estimate and an outline of, and rationale for, any areas that deviate from the Functional Specification.
   - Once the AESO accepts the TFO's PPS, the AESO issues direction to the TFO to prepare and file, with the Board, a Facilities Application based on scope, costs, and schedule described in the TFO's PPS and the AESO Functional Specification.

4. EUB Process
   - The Board reviews the Facility Application.
   - The Board processes provide opportunity for stakeholder involvement.
   - The Board may approve, conditionally approve, or deny.

It should be noted that while the Alberta framework requires an application

[15] See AESO, *Rules for Transmission Facility Projects, Discussion Paper*, May 30, 2005.

to address benefits to such factors as system reliability, efficiency and competition, it does not require a comprehensive cost-benefit analysis to be carried out. The first project to be approved under Alberta's new regulatory framework calculated only the project's capital cost less the value of the reduction in line losses.[16]

6. Other Issues for Discussion

- Are there other methods of transmission investment evaluation that the Board should be examining?
- Should the benefits of increased competition be included in the test? How should they be assessed?
- What role should probabilistic reliability standards play in the test? How should the benefits of investments that exceed minimum reliability standards be evaluated?
- How can the test ensure that network and non-network investments are treated appropriately?
- What is required to keep the test computationally manageable?
- What role(s) should the IESO and OPA play in the cost-benefit test (e.g., data provision, examination of alternatives) and transmission investment applications in general?
- Are there any specific existing network analysis software applications that are acceptable to use to fulfill the requirements of the proposed test (e.g., GE Maps)?
- Are there any other relevant issues that the Board should consider?

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[16] See Alberta Energy and Utilities Board, *Alberta Electricity System Operator, Needs Identification Document Application, Edmonton Calgary, 500 kV Electric Transmission Facilities*, Decision 2005-031, April 14, 2005.

7. Appendix A: Potential Investment Test

This section describes a potential test that could be used to evaluate transmission infrastructure investments. The potential test was developed by OEB staff and based on the transmission investment cost-benefit tests developed in Australia and New Zealand. The test would be applied to transmission investments covered by section 92 of the Act.

The test identifies two types of transmission investment projects: (1) projects proposed to meet established network performance standards (e.g., the Transmission System Code, regulatory standards) and (2) other projects, such as projects proposed to realize economic benefits (e.g., reduced congestion) and/or enhance system reliability beyond minimum performance requirements.

The potential test establishes the methodology and parameters (e.g., the value of unserved energy) to be used to evaluate proposed investments and the evidence on costs and benefits that would be considered. It sets out the criteria for accounting for uncertainty (e.g., future demand growth, weather) and examining alternatives (e.g., distributed generation) to proposed transmission investments.

The Board has made no decisions at this stage about the type of investment test or filing requirements that it will ultimately adopt. The OEB staff developed the potential test outlined below for review and discussion by a Technical Advisory Team. After considering the input of the team on the conceptual and practical merits of the potential test, the Board will develop a draft test and draft filing requirements that will be released for public comment.

It is expected that applicants seeking leave to construct will need to collaborate with other organizations (e.g., the IESO and OPA) to fulfill the requirements of any investment test that the Board ultimately adopts.

Terms in italics are defined in the "Definitions" section of the test.

The test:

(1) A proposed transmission investment satisfies the cost/benefit test if:

> (a) in the event the proposed investment is necessitated solely by the inability to meet the minimum network performance requirements set out in the Transmission System Code or in relevant legislation, regulations or statutory instrument or relevant planning criteria which are part and parcel of good utility practice (as defined in the Transmission System Code)[17] -

[17] In the Transmission System Code, good utility practices are "any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable

the proposed investment maximizes the expected net present value of the *market benefit* (or in other words the present value of the *market benefit* less the present value of *costs*) or minimises the present value of *costs*, compared with a number of *alternative options* in a majority of *reasonable scenarios*;

(b) in all other cases - the proposed investment maximizes the expected net present value of the *market benefit* compared with a number of *alternative options* and timings, in a majority of *reasonable scenarios* and the expected net present value of the proposed investment is greater than zero.

(2) Only direct costs and benefits to all those who produce, distribute and consume electricity in the Ontario electricity market should be included; any additional indirect costs or benefits (associated with the Ontario economy in general) should be excluded from the assessment.

(3) The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used should be consistent with the cash flows being discounted.

(4) The analysis must include modelling a range of reasonable *market development scenarios*. These should incorporate varying levels of demand growth at relevant load centres (reflecting demand side proposed investments), alternative project commissioning dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative construction timetables as nominated by the proponent providing that relevant reliability standards would be met.

Market development scenarios must include:

(a) *Committed projects*;

(b) *Anticipated projects*;

(c) *Modelled projects*; and

(d) any other technically feasible projects identified during the application process.

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judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good utility practice is not intended to be limited to optimum practices, methods or acts to the exclusion of all others, but rather to include all practices, methods or acts generally accepted in North America."

(5) The calculation of the *costs* or *market benefits* must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on, but not limited to, the following, and should be appropriate to the size and type of project:

(a) *Market benefits*:

(i) Using all reasonable methodologies; and

(ii) Testing reasonable forecasts of the value of electricity to consumers.

(b) Capital and operating costs of *alternative options*.

(c) Discount rate (the lower boundary should be the regulated cost of capital).

(d) Market demand.

(e) Generation bidding behaviour using:

(i) Short-run marginal cost; and

(ii) Approximations of realistic bidding if measuring competition benefits.

(f) Estimated commissioning dates of:

(i) Alternative projects;

(ii) Committed projects;

(iii) Anticipated projects; and

(iv) Modelled projects.

(g) The timing of decommissioning, removing or de-rating *decommissioned assets*

(h) Other sensitivity testing determined to be relevant and material to the case concerned.

(6) Any relevant information which may have a material impact on the determination of *costs* or *market benefits* which comes to light at any time before an assessment is finalised must be considered and made available to interested parties.

Definitions:

(7) *Market benefit* means the total benefits of a proposed investment (or an *alternative option*) to all those who produce, distribute and consume electricity in the Ontario electricity market. That is, the change in consumers' plus producers' surplus[18] or another measure that can be demonstrated to produce an equivalent ranking of proposed investments in a majority of *reasonable scenarios*. For clarity, *market benefit* does not include the transfer of surplus between consumers and producers, as this is simply a reallocation. In determining the *market benefit*, the analysis may include, but need not be limited to the following benefits arising from:

(a) reductions in fuel consumption arising through different generation dispatch;

(b) reductions in the costs of demand-side management;

(c) reductions in the value of involuntary load shedding (i.e., lost load);

(d) reductions in costs resulting from the deferral of capital expenditure on *anticipated* and *modelled* projects;

(e) reductions in costs resulting from differences in the amount of capital expenditure on *anticipated* and *modelled* projects;

(f) reductions in costs resulting from differences in operations and maintenance expenditure on existing assets, *committed* projects, *anticipated* and *modelled* projects;

(g) reductions in transmission line losses;

(h) reductions in the cost and changes in the nature of ancillary services;

(i) *competition benefits*; and

(j) other benefits that are determined to be relevant to the case concerned.

(8) *Competition benefits* mean the direct or indirect effects of greater competition between generators resulting from a *proposed investment* or *alternative options* on:

(a) generation bidding behaviour;

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[18] Consumer surplus is the difference between what consumers are willing to pay for a commodity and the amount they actually paid. Producer surplus is the difference between the minimum price that producers would accept to supply a given level of output and the actual price producers receive.

(b) the estimated in service date of *anticipated* and *modelled* projects.

(9) *Costs* means the total cost of a proposed investment (or an *alternative option*) to all those who produce, distribute or consume electricity in Ontario's electricity market. In determining the *costs*, the analysis may include, but need not be limited to, the following:

(a) costs incurred in constructing or providing the proposed investment;

(b) operating, maintenance and removal costs over the operating life of the proposed investment;

(c) the cost of complying with existing and anticipated laws, regulations and administrative determinations;

(d) other costs that are determined to be relevant to the case concerned.

(10) *Alternative option* means:

(a) For a proposed investment in accordance with paragraph 1(a) of this test:

(i) a genuine alternative to the proposed investment being assessed, in that it has a clearly identifiable proponent; and

(ii) a practicable alternative to the proposed investment being assessed in that it is technically feasible.

(b) For a proposed investment in accordance with paragraph 1(b) of this test:

(i) a genuine alternative to the proposed investment being assessed, in that it:

(A) delivers similar outcomes to those delivered by the proposed investment being assessed; and

(B) becomes operational in a similar timeframe to the proposed investment being assessed;

(ii) a practicable alternative to the proposed investment being assessed in that it is:

(A) technically feasible; and

(B) commercially feasible, which is to be demonstrated by determining whether an operator, acting rationally according to the economic criteria prescribed by this test,w ould be prepared to construct or provide the *alternative option*.

The existence of a genuine proponent for the *alternative option* should be taken into account when determining practicability, however, absence of such a proponent will not exclude a project from being an *alternative option* for the purposes of the regulatory test.

Both transmission and *non-transmission* investments can be *alternative options*, where *non-transmission* alternatives include, but need not be limited to, the following:

(i) generation;

(ii) demand-side management; and,

(iii) distribution network augmentation.

An *alternative option* should be reasonably likely to proceed if neither the proposed investment nor any other *alternative option* proceeds and unlikely to proceed if the proposed investment does proceed.

(11) *Reasonable scenarios* mean scenarios incorporating:

(a) reasonable forecasts of:

(i) the size, timing and location of electricity demand growth (modified where appropriate to take into account demand-side proposed investments, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);

(ii) the size, location and timing of *committed*, *anticipated* and *modelled* projects including demand side and generation projects;

(iii) the operating and maintenance costs of efficiently supplying energy to meet forecast demand from existing assets, and *committed*, *anticipated* and *modelled* projects including demand side and generation projects;

(iii) the avoidable costs of *committed,an ticipated* and *modelled* projects including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred;

(iv) the cost of providing sufficient ancillary services to meet the forecast demand;

(v) the timing and cost of decommissioning, removing or de-rating *decommissioned assets*; and

(vi) the capital and operating costs of other regulated network projects that are augmentations consistent with the forecast demand and generation scenarios

(b) scenarios defined as *market development scenarios*; and

(c) sensitivity testing.

(12) *Decommissioned assets* means existing assets that are reasonably likely to be decommissioned, removed or de-rated in a similar timeframe regardless of whether or not the proposed investment or alternative project proceeds and in relation to which either:

(a) both of the following are satisfied:

(i) a final decision to decommission, remove or de-rate the existing asset after a specified date has been made and has been publicly announced; and

(ii) contracts to directly or indirectly facilitate the decommissioning, removal or de-rating of the existing asset have been finalised and executed; or

(b) consents or contracts for the operation and maintenance of the existing asset have been terminated or have expired with no reasonable prospect of renewal, or in relation to which agreements for early termination have been finalised and executed.

(13) *Committed project* means a transmission or *non-transmission* project which satisfies all the following criteria:

(a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;

(b) construction of the project must either have commenced or a firm commencement date must be set;

(c) the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed project;

(d) contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) are finalised and executed, including any provisions for cancellation payments; and

(e) the financing arrangements for the proposal, including any debt plans are finalised and contracts executed.

(14) *Anticipated project* means a transmission or *non-transmission* project which:

(a) does not meet each of the criteria in paragraph 13; and

(b) is in the process of meeting one or more of the criterion in note 13.

(15) *Modelled project* means a transmission or *non-transmission* project (other than a *committed* project or *anticipated* project), which is:

(a) likely to occur in a *market development scenario*;

(b) reasonably expected to occur in that market development scenario within the time horizon for assessment of the market benefits and costs of the proposed investment and alternative projects; and

(c) affected, in terms of likelihood, nature and timing, by whether the proposed investment, alternative project or any anticipated project proceeds.

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